

Residential application of internal combustion engine based cogeneration in cold climate—Canada

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ABSTRACT

The objectives of this work are to model a group of test case houses using a high-resolution building simulation program, to evaluate the efficiency of internal combustion engine (ICE) based cogeneration and to determine the economical (in terms of fuel cost) impact of using ICE based cogeneration systems for residential use. The performance in terms of electrical and CHP efficiencies of the ICE based cogeneration systems in Canada were investigated and it was determined that the performance of the ICE based cogeneration system is dependent on the thermal and electrical loads of the house, on climate, especially the severity and duration of the heating season, and on the constructional characteristics of the house. Although the annual fuel cost of the household would increase, the ICE based cogeneration systems can provide savings in various aspects regarding electricity production and distribution.

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1. Introduction

Cogeneration, or the simultaneous production of electricity and useful heat using one fuel stream, offers a way of increasing fuel efficiency while decreasing emissions when compared to conventional electrical and thermal energy generation. Residential cogeneration is an attractive option for increasing energy efficiency and decreasing greenhouse gas (GHG) emissions as residential cogeneration systems can achieve energy conversion efficiencies of up to 80% (based on HHV) as compared to 30–35% (HHV) efficiency obtained through conventional fossil fuel based electricity production and up to 55% (HHV) for combined cycle plants, such as combined cycle gas turbine. Higher efficiency translates into reduced GHG emissions and reduced fuel costs. Moreover, there are several technologies suitable for residential cogeneration currently available or under development including reciprocating internal combustion engine, micro-turbine, fuel cell, and reciprocating external Stirling engine based cogeneration systems. Cogeneration is a well-proven technology that has been used for over 125 years. Knight and Ugursal [1] state that its first appearance was in industrial plants in the 1880s when steam was the primary source of energy in industry and electricity was just surfacing as a product for both power and lighting. With respect to single-family dwellings,

there are several systems that could be applicable including reciprocating internal combustion engine (ICE) (spark ignition – gasoline, natural gas, propane, or compression ignition – diesel), micro gas turbine based systems, fuel cell based systems and Stirling engine based systems. Onovwiona and Ugursal [2] showed that any of these systems could be used in place of a boiler or furnace and used to produce the required thermal and electrical energy while surplus energy could be sold to the local utility grid or stored in an energy storage device. Watson et al. [3] found that the payback time for micro-CHP is considerably shorter than other renewable micro generation systems namely PV and wind.

Internal combustion based systems are able to achieve higher efficiencies at lower power ranges than micro-turbine based cogeneration systems. As fuel cell based cogeneration is still an emerging technology, high cost and short lifetime are the major disadvantages of this system. Stirling engine based cogeneration systems for residential applications are also very costly at this stage. Fig. 1 shows a schematic of a cogeneration system based on IC engines.

In this study, the feasibility of IC engine based cogeneration system for single detached houses in comparison with traditional practices has been studied.

2. Simulation tool and methodology

Building simulation is a powerful tool used to aid in the assessment of renewable energy technologies in buildings. With

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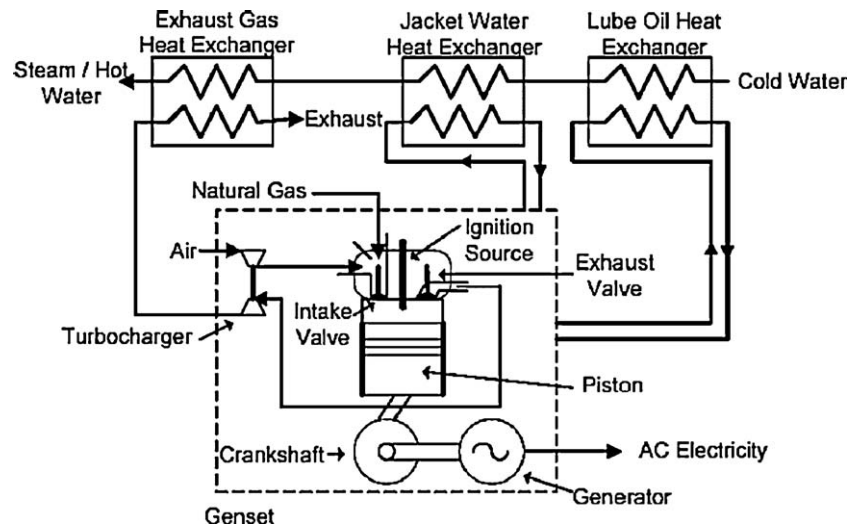


Fig. 1. An internal combustion engine based cogeneration system [7].

respect to both environmental impacts and economics, it is important that critical design decisions can be tested and analyzed using building simulation [4]. ESP-r is a transient building energy simulation program developed and maintained by Energy Systems Research Unit (ESRU) at the University of Strathclyde [5]. It is an integrated modeling tool for the simulation of the performance of buildings in terms of thermal, visual and acoustic performance as well as the assessment of the energy use and gaseous emissions associated with the environmental control system and constructional materials [6]. Modeling in ESP-r can be achieved using the *Project Manager* [7]. The ICE based cogeneration system model developed by Onovwiona [8] for the ESP-r platform will be used as the simulation tool for the analysis. Onovwiona et al. [9] used a constant output control model that has some advantages however it would require battery storage thus increasing cost and complexity of the system. To avoid the mentioned obstacles, an electrical load following controller has been used in the current study. Moreover, a thorough sensitivity analysis will improve understanding of the performance of ICE based cogeneration systems and will allow for conclusions to be drawn regarding the sizing of ICE based cogeneration systems in residential applications. To provide an indication of the potential economic savings and reductions in GHG emissions using ICE based cogeneration in single detached Canadian homes, information from three publicly available Canadian databases was used to model test case houses in ESP-r to be used in building energy simulations. The Survey of Household Energy Use (SHEU) database [10] was the main database used, however was lacking vital information, therefore two other databases were also used namely, the EnerGuide for Houses (EGH) database [11] and the New Housing Survey (NHS) database [12]. Only houses heated by natural gas or oil were considered in this project as houses heated by either electricity or wood do not have the necessary infrastructure needed to install an ICE based cogeneration system.

Two sets of simulations were conducted to estimate the thermal and electrical demands of the test case houses. The first set of simulations was conducted using conventional methods, for example, natural gas or oil fuelled furnace and domestic hot water tank, and electricity from the grid, and the second set of simulations was conducted using ICE based cogeneration. A sensitivity analysis was performed on the ICE based cogeneration model to study the impact on cost of varying the ICE and thermal storage tank capacities. Two ICE capacities (1 kW and 2 kW) and two hot water storage tank sizes (300 l and 450 l) were simulated in each of the test case houses. The simulation results from all

simulations, using conventional methods and ICE based cogeneration, were analyzed on the basis of cost, using a flat rate and time-of-use (TOU) electricity pricing scheme. Conclusions were drawn regarding the economic and environmental impacts of using ICE based cogeneration in single detached Canadian homes. High-rise apartments and mobile homes were not considered in this study. Single detached houses account for 70% of the SHEU database.

To facilitate modeling, the houses were classified into various categories. The first step in classification process was by province. Once classified by province, the data was classified by vintage, namely before 1941, 1941–1960, 1961–1977 and 1978 and later, and further classified by space heating fuel type, namely natural gas and oil. The NHS database was classified on the basis of province only as there were not enough entries to allow for further classification. The detail of the classifications is given in Aussant [13]. To provide an indication of the potential energy savings using ICE based cogeneration in single detached Canadian homes, three representative house archetypes were selected for each province as test case houses.

A sample test case house specification is given in Table 1.

3. Load profile

It is well known that residential electricity demand varies with socio-economic factors such as household income, dwelling type and ownership, and number of children and adults [14]. The availability at home of each household member and their associated home activities also affects the household electricity demand [15]. In addition, the shape and magnitude of load profiles also vary with factors such as time of day, time of year, geographical location, and climate [16,17]. Due to the absence of load profile data, rather than using arbitrary load profiles, electricity load profiles based on data from British Columbia (BC) Hydro were used in this study. The BC Hydro electricity load profiles are categorized according to geographical regions within British Columbia, namely the Northern, Southern Interior, Lower Mainland, and Vancouver Island regions. The details of each test case house, namely the region, annual electricity consumption, house size, number of occupants and the primary space heating fuel were used to determine which of the best-match files were to be used in generating the specific load profile. For example, test case house 1 is in British Columbia, has an annual electricity consumption of 10,000 to 19,999 kWh, is between 0 to 1499 ft² (139 m²), has three occupants and uses natural gas as the space heating fuel. The data for each of the five categories was

Table 1

Test case house 1—specifications.

House orientation	South
House size (m ²)	116
Number of storeys	1
Number and construction of doors	3: wood
Basement	Full basement
Main wall RSI (K m ² /W)	1.75
Foundation RSI (K m ² /W)	1.82
Ceiling RSI (K m ² /W)	3.91
Roof RSI (K m ² /W)	0.26
Attic	Full attic
External wall material	Wood
Space heating equipment type	Furnace w/cont. pilot
Space heating equipment efficiency (%)	77
Space heating fuel type	Natural gas
DHW tank size (l)	180
DHW equipment type	Conventional w/pilot
DHW fuel	Natural gas
DHW efficiency (%)	51
Basement heating	Whole basement heated
Number of occupants	3
Temperature set 1: 6AM–6PM (°C)	20
Temperature set 2: 6PM–10PM (°C)	21
Temperature set 3: 10PM–6AM (°C)	18
ACH @ 50 PA	8.07

normalized and all five normalized profiles were averaged. The resulting normalized average load profile was used to generate the absolute load profile specific to test case house 1.

Due to the high prediction performance, the estimates determined using the neural network (NN) model, were used to determine the annual electricity consumption for the test case house group. Specifically, the weighted average of the annual electricity consumption for the test case house group using the NN estimates provided in Aydinalp [18] was determined. It had to be decided which region in British Columbia could be used to represent the remaining regions in Canada. To facilitate this extrapolation, the heating degree-day (HDD) for each region was determined and compared to the HDD for each of the four regions in British Columbia. All degree-day data was taken from Environment Canada [19]. Fig. 2 shows an average daily electricity load profile for test case house 1 where winter is December to February, spring is March to May, summer is June to August and fall is September to November. The load data for each day in each season was averaged to illustrate the average daily electricity load profile for each season. It should be noted that no air conditioning device was used and taken into account in modeling the house.

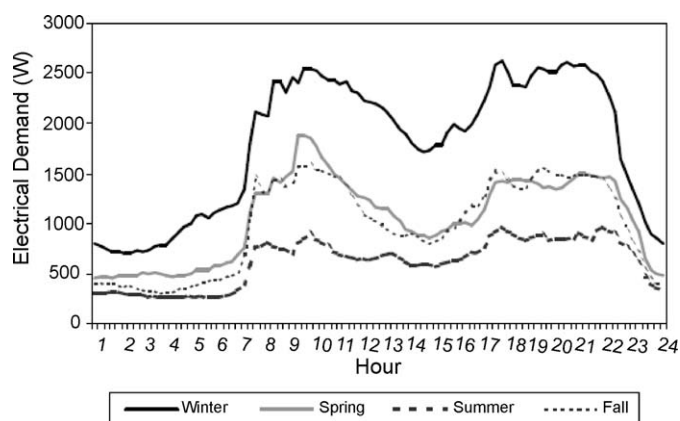
ESP-r requires a year of assessment to be defined when creating a house model and generates a calendar specifying the weekdays and weekends. The year defined in the weather file was used as the year of assessment to ensure that weekdays and weekends matched as both control strategies and casual gains schedules differ depending on the type of day (i.e.: weekday or weekend). ESP-r uses readily available databases to gather information for solving the set of equations. The test case specific databases are given by Haugaard [20].

Table 2 details the dimensions used for houses of different sizes and different numbers of storeys.

Table 2

Test case house interior dimensions.

Number of storeys	1250 ft ² (116 m ²)			1750 ft ² (163 m ²)		
	Width (m)	Depth (m)	Main wall height (m)	Width (m)	Depth (m)	Main wall height (m)
1	10.78	10.78	2.50	13.55	12.00	2.50
1.5	10.78	10.78	3.75	13.55	12.00	3.75
2	7.62	7.62	2.50	9.02	9.02	2.50

**Fig. 2.** Average daily electricity load profile.

All wall heights were 2.5 m, with the exception of 1.5 storey test case houses. In this case, the basement was modeled with a 2.5 m wall height, and the main floor with a wall height of 3.75 m.

The data required for modeling doors and windows in ESP-r was derived from both the SHEU database and the NHS database. The SHEU database details the number and type (i.e. single pane, double pane or triple pane) of windows, and the NHS database details the distribution of the windows. Table 3 details the window sizes used.

The Alberta Infiltration Model (AIM-2) is used to account for airflows and infiltration in ESP-r. Details on the AIM-2 model can be found in Walker and Wilson [21]. To quantify the casual gains due to occupancy, a schedule of activities and associated latent and sensible gains had to be determined. The occupancy patterns used in this study were based on the CCHT simulated occupancy schedule [22]. To avoid overestimating the occupancy casual gains, a schedule was set for the first occupant and a modified schedule was set for the remaining occupants. Activities with high associated metabolic rates such as cooking and cleaning are rarely performed by all occupants at the same time therefore it was assumed that one occupant performed these tasks while the remaining occupants performed more moderate activities. In the base case, the test case houses were modeled using idealized HVAC. Idealized HVAC models can be coupled to the idealized controllers to estimate system performance. Idealized controllers look at the space heating and cooling loads required at each time step and perform the necessary heat/moisture addition/extraction. Idealized HVAC models do not actually simulate system response, but instead look at the heat injection/extraction calculated by the idealized controls and estimate the system's fuel use based on this operational pattern [23]. While it was possible to use the idealized DHW model in the base case, it was desirable to ensure that the base and ICE cases remained as comparable as possible, thus the 3-node DHW tank model was used in both the base and ICE scenarios. In the base case, the HVAC loads were met by idealized HVAC therefore ICE was not activated. In addition, the pumps between the DHW storage tank and ICE and the DHW tank and the heating coil were not activated. In this way, the DHW model met the DHW load while idealized HVAC met the space-heating load. While

Table 3
Window sizes [12].

Window type	Length × width dimensions (m)	Glazed area (m ²)
Large	1.09 × 1.09	1.188
Regular	0.89 × 0.89	0.79

information on the DHW efficiency was available in the EGH database, there was no information available on the DHW heat injector rate—a required user input for the DHW model.

4. Cogeneration plant model

The plant configuration used in the ICE based cogeneration simulations is illustrated in Fig. 3.

In the cogeneration case, the thermal energy from the ICE based cogeneration system was transferred to the storage tank. The space heating requirements were met by the heating coil, which was fed by the hot water storage tank. The backup burner on the hot water storage tank ensured that the temperature in the tank did not go below the required temperature. The ICE cogeneration system was modeled using ESP-r's 3-node ICE model, which requires one water connection. The ICE model used in this study is a simplified parametric model based on performance data quoted by manufacturers of commercially available reciprocating ICEs with rated output in the 1–10 kW range suitable for residential applications [9]. The model assumes a constant overall efficiency of approximately 80% (based on LHV). Based on this assumption and the performance data from a 6 kW Cummins gas engine, the variation of the specific fuel consumption (SFC), electrical efficiency, and heat to power ratio (HPR) as a function of part load ratio are estimated using second and third order polynomials. The fuel used to run the ICE based cogeneration system was natural gas or propane, depending on the fuel used in the base case simulations. For test case houses 1–15, the fuel used in the ICE based cogeneration cases was natural gas. For test case houses 16–30, the fuel used in the ICE based cogeneration cases was propane.

The hot water tank was modeled using ESP-r's 3-node hot water tank with a back-up burner. There are two options in defining the DHW draw profile, user-defined or a draw profile based on the CSA f379.1-88 Solar Domestic Hot Water System. The CSA f379.1-88

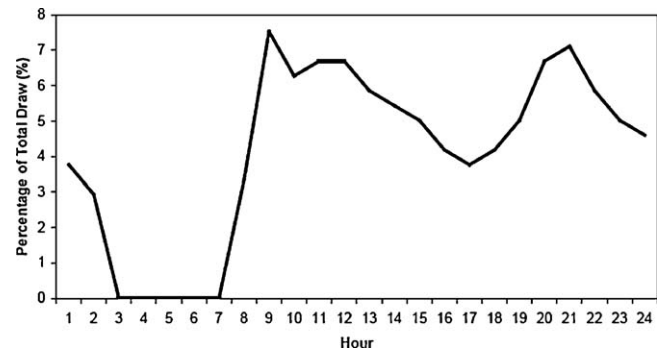


Fig. 4. DHW draw profile.

Solar Domestic Hot Water System was assumed for this study and the draw profile is illustrated in Fig. 4 [24].

For all ICE based cogeneration simulations, the backup burner efficiency was assumed to be 80% (based on HHV) and the UA value for the tank was assumed to be 1.175 W/K.

The pumps were modeled using ESP-r's single-node wet central heating (WCH) pump. The flow rate for the ICE pump was $1.26 \times 10^{-4} \text{ m}^3/\text{s}$ and the flow rate for the heating coil pump was $3.0 \times 10^{-4} \text{ m}^3/\text{s}$ and the rated power for each pump was 150 W.

The hot water storage tank was controlled by sensing the temperature of the water inside the tank. The DHW supply temperature was 55 °C and a six-degree temperature band was used, thus the lower set point was 52 °C and the upper set point was 58 °C. If the temperature in the tank fell below 52 °C, the backup burner would be activated until the temperature in the tank reached 58 °C, at which point it would shut off. This was to ensure that the water temperature stayed within range of the required DHW temperature, and to prevent the backup burner from repeatedly cycling on and off. In the ICE case, control loops were imposed on some of the plant network components, namely the hot water storage tank, the supply fan and the pump between the hot water tank and the fan coil. A control loop consists of a sensor, an actuator, and an associated control law. The plant network was controlled using three control loops. In addition, temperature limits were imposed for the tank's heat dump facility, which is used to ensure that the water in the tank does not boil. The heat dump facility was activated if the temperature in the tank reached

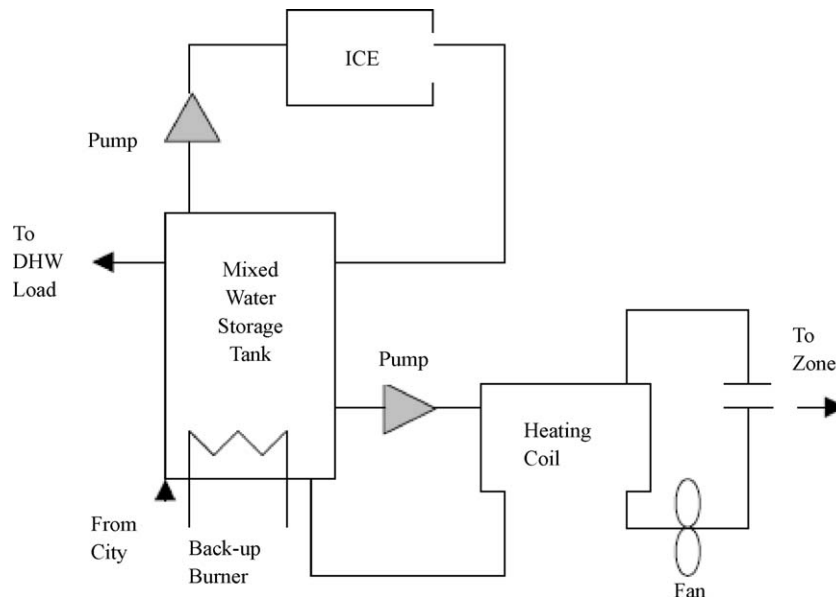


Fig. 3. ICE based cogeneration case plant configuration.

85 °C and deactivated when the temperature in the tank fell to 80 °C. The control loop used to control the fan sensed the dry-bulb temperature in the main zone and actuated the fan and was implemented using on-off control. Unlike the idealized HVAC model, a temperature band was required instead of a temperature set point. The temperature band used was a 1 °C temperature band around the desired set point temperature. In both the base and cogeneration cases, heat was injected into the main zone and an inter-zone ventilation rate of 2.616 ACH was imposed to move heat to the remaining zone(s). The control loop used to control the heating-coil pump sensed the dry-bulb temperature in the main zone and actuated the heating coil pump and was implemented using on-off control. As with the fan control, a 1 °C temperature band around the desired set point temperature as defined in the test case house descriptions was used. The control loop used in controlling the ICE unit was modeled within the ICE model itself, and no external control was required. The ICE unit operated by following the electrical load of the building, called electricity priority control.

5. Simulation results and analysis

All simulations were run using fifteen-minute time steps for both the building and plant domains. According to Good et al. [25] and Fung et al. [26], using fifteen-minute time steps allows for a good sub-hourly representation of building loads and system response. Since all results in this study were analyzed on an annual basis, using five-minute or one-minute time steps was not necessary. In addition, to ensure that the initial building and plant conditions did not affect the results, a start-up time of three days was specified for all simulations. In order to determine the appropriate furnace capacity, annual simulations using fifteen-minute time steps were run with each test case house using a furnace of 50 kW capacity. The results of these simulations were used to determine the capacity of the furnace for each test case house. Specifically, the furnace output was analyzed and the highest value identified. The maximum required furnace output was multiplied by a safety factor of 1.2 and rounded to the nearest kilowatt, and this value became the furnace capacity for the test case house. The largest furnace capacity of 40 kW was considered for Fredericton, NB and the smallest capacity of 8 kW was required for Vancouver, BC.

Once the appropriate furnace size was determined, the base case simulations were run. The test case houses used in the base case simulations were modeled with conventional technologies (i.e. natural gas/oil fired furnace and natural gas/oil/electricity based DHW system). Annual simulations were run for each test case house, in their corresponding simulation cities. The results of the base case simulations were used as the basis of comparison for the subsequent ICE based cogeneration simulations.

The conventional energy systems used in the base case simulations were replaced by an ICE based cogeneration system and annual simulations using fifteen-minute time steps were run. To quantify the effect of varying ICE system parameters on the system performance in terms of cost (sensitivity analysis), annual simulations were run with four different ICE based cogeneration system configurations. Two ICE sizes and two storage tank sizes were used in the cogeneration simulations. The ICE based cogeneration system used in this study is controlled by following the electrical demand of the house. To determine the size of ICE used in simulations, a frequency plot was generated illustrating the levels of electricity demand. Fig. 5 illustrates the frequency distribution of the electrical demand of three test case houses. The test case houses with the highest and lowest electrical demand in the base case simulations are plotted, as well as a test case house with an average total electrical demand.

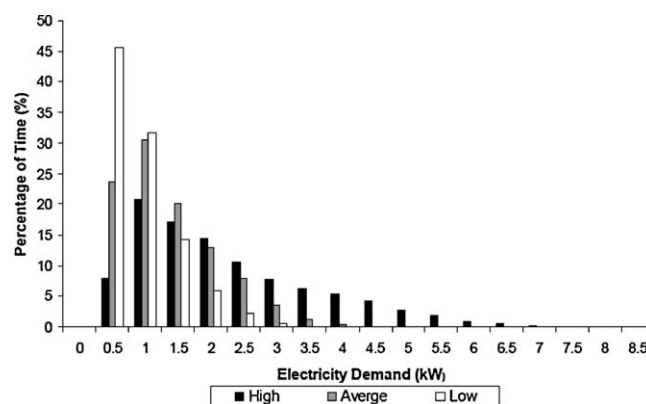


Fig. 5. Electricity demand frequency plot.

It is desirable to minimize running the ICE at part load as the electrical efficiency decreases as the part load ratio decreases. In addition, according to Fig. 5, the majority of the time the houses' electrical demand falls between 500 W and 2.0 kW (i.e. 60% for high electrical demand, 87% for average electrical demand, and 97% for low electrical demand), thus the ICE sizes used in simulations were 1.0 kW and 2.0 kW. Among the literature currently available regarding the feasibility of ICE based cogeneration in residential applications, there is no indication of the sizes of thermal storage used. Onovwiona et al. [9] simulated a 2.0 kW, 3.5 kW and 6.0 kW ICE based cogeneration system with associated tank sizes of 300 kg and 600 kg. As the ICE capacities in the current work are 1.0 kW and 2.0 kW, it was decided that 300 kg and 450 kg tanks were to be used in simulation. In addition, both of the chosen tank sizes are commercially available.

To investigate the effect of using a larger ICE and thermal storage size, the three Prince George test case houses were simulated with a 3.0 kW ICE and 1000 kg storage tank. The reason for the selection of the Prince George test case houses is that they have the highest electrical demand of all of the test case houses, while are among the highest thermal demand cases.

The ICE based cogeneration simulations were run and the results compared to the base case simulation results. Both the base case and ICE based cogeneration results were analyzed on the basis of cost, using both a flat rate and a time-of-use pricing scheme for the cost of electricity. Tables 4 and 5 present a summary of the annual simulation results and constants for test case house 10 simulated in Le Pas, Manitoba and are used in the subsequent sample calculations. The energy requirement for the idealized HVAC system and the DHW burner are based on the HHV of the fuel used, while the energy requirement for the ICE is based on the LHV of the fuel used. A furnace efficiency of 78% and a DHW efficiency of 54.3% were used as base case constants in the model.

In both the base and ICE based cogeneration cases, the total cost is based on the cost of the fuel used for space and DHW heating as

Table 4
Base case annual simulation results—test case house 10, Le Pas.

Electricity consumption (kWh/yr)	10211
Space heating energy requirement (GJ/yr)	122.28
DHW energy requirement (GJ/yr)	24.33

Table 5
ICE case annual simulation results—test case house 10, Le Pas, 2 kW, 300 l.

ICE total fuel consumption (kg/yr)	4476.7
Backup burner output (GJ/yr)	46.16
Total electrical demand (kWh/yr)	11504
Total ICE electrical output (kWh/yr)	10512
Total grid import (kWh/yr)	992

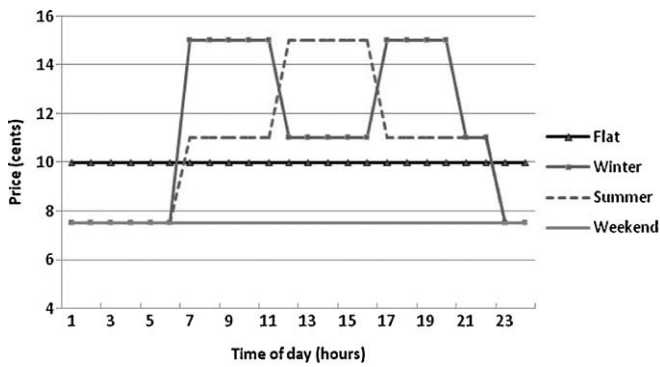


Fig. 6. TOU electric pricing [27].

well as the cost of electricity, based on both flat rate and TOU pricing. Fig. 6 shows TOU electricity pricing in Ontario. The prices of natural gas, heating oil and propane (including delivery) used in this analysis are given in detail in Aussant [13].

In the ICE based cogeneration case, the fuel consumption is determined by summing the total fuel consumption of the ICE and the back-up burner output. The cost of natural gas is calculated by multiplying the total consumption in cubic meters by the price of natural gas in €/m³. The cost of electricity is determined using a flat rate and a TOU pricing structure. The same approach is used for both the base and ICE based cogeneration cases, however in the ICE based cogeneration case, the cost of electricity represents the cost of grid-imported electricity. The total cost of electricity using the TOU scenario is calculated by summing the product of electricity demand and the cost of electricity at each time-step. The cost of electricity using the TOU pricing scheme in the ICE case represents the cost of grid-imported electricity.

5.1. CHP efficiency

The CHP efficiency of the ICE based cogeneration system is presented in Fig. 7 as a function of the total annual thermal demand (space and DHW thermal demand) of the test case house and a sample annual case study results for British Columbia is shown in Table 6.

In general, the CHP efficiency of the 1.0 kW system is higher than the 2.0 kW system as more of the heat generated can be utilized. The 2.0 kW system produces more surplus heat than the 1.0 kW system, thereby reducing the annual CHP efficiency. Using the 1.0 kW system, the annual CHP efficiencies are between ~40% and 65% and using the 2.0 kW system, the annual CHP efficiencies are between ~30% and 45%. The correlation between annual thermal demand and annual CHP efficiency is not strong ($R^2 < 0.15$) because there are many factors that affect the annual CHP efficiency other than total annual thermal demand. Factors including the thermal output from the ICE based cogeneration system, electrical demand of the test case house, electrical efficiency of the ICE based cogeneration system, length and severity of the heating season, and temporal thermal demands all

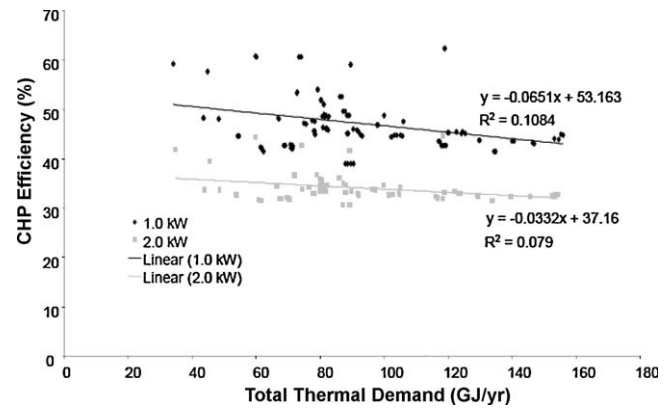


Fig. 7. Total thermal demand vs. CHP efficiency.

affect the annual CHP efficiency. Fig. 8 illustrates the annual CHP efficiency versus the quotient of test case house annual electrical demand ($Demand_{el}$) and annual space heating demand ($Demand_{SH}$).

In general, the annual CHP efficiency increases as the ratio of electrical to space heating demand increases. The test case houses in British Columbia have high (>1000 kWh/GJ = 3.6 GJ/GJ) electrical demand to space heating demand ratios due to their high electrical demands (~20,000 kWh/yr). Including the effect of test case house specific annual electrical demand, results in an increase in the prediction performance to $R^2 \approx 0.5$.

5.2. Fuel cost

In all cases, the fuel cost in the cogeneration simulations is greater than the fuel costs in the base case. In the base case, only the energy required by the house was consumed, either through grid-imported electricity, or consuming fuel for the space and domestic hot water heating equipment. Since the cogeneration system used in this study followed the electricity demand of the house, heat was generated all year, which could not be fully utilized during the non-space heating months. The inability to fully utilize all of the generated energy leads to a fuel cost increase in all cases. The change in total fuel cost (natural gas/propane and electricity) compared to the base case is calculated according to Eq. (1) where a negative value indicates an increase in fuel cost

$$\Delta \text{cost} (\%) = \frac{\text{cost}_{\text{BC}} - \text{cost}_{\text{ICE}}}{\text{cost}_{\text{BC}}} \times 100 \quad (1)$$

Fig. 9 presents the increase in fuel cost for the ICE based cogeneration simulations.

The economic viability of the ICE based cogeneration system in terms of fuel costs is dependent on the provincial fuel and electricity prices. The ICE based cogeneration system displaces grid-imported electricity in place of increased fuel consumption, thus the economics are favorable in provinces with relatively high electricity prices and relatively low fuel prices. A comparison of the

Table 6
Summary of annual ICE based cogeneration simulation results—British Columbia.

System	#	$\Delta \text{Cost} (\%)$					
		Test case house 1		Test case house 2		Test case house 2	
		Prince George	Vancouver	Prince George	Vancouver	Prince George	Vancouver
1.0 kW, 300 kg	1	−3.9	−13.9	−15.2	−30.9	−15.2	−29.8
1.0 kW, 450 kg	2	−5.5	−14.4	−16.0	−31.0	−16.9	−30.2
2.0 kW, 300 kg	3	−10.8	−36.2	−42.5	−80.8	−33.8	−71.6
2.0 kW, 450 kg	4	−13.0	−36.2	−42.6	−81.0	−34.5	−71.9

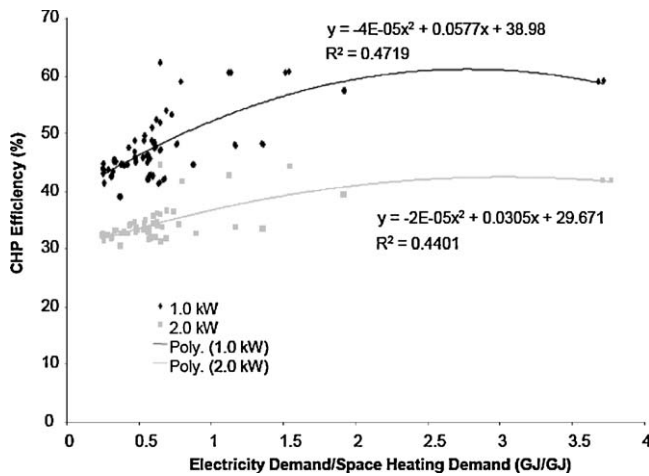


Fig. 8. Demand_{el}/Demand_{SH} vs. CHP efficiency.

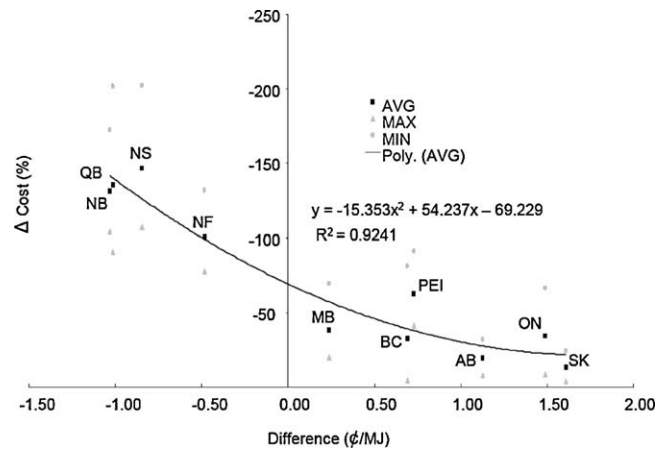


Fig. 10. Fuel cost difference vs. delta cost.

results in Saskatchewan and Manitoba highlight this difference. In Saskatchewan, the prices are 34 ¢/m³ and 8.99 ¢/kWh for natural gas and electricity, respectively. In Manitoba, the prices are 51 ¢/m³ and 5.69 ¢/kWh, for natural gas and electricity respectively. The ICE based system is more economically viable in Saskatchewan with a cost difference compared to the base case for system 1 (as defined in Table 6) of between –19.6% and –5.0% compared to –80.9% to –3.1% for the same system in Manitoba. In addition, the difference in fuel costs between the base and ICE based cogeneration cases in New Brunswick, Nova Scotia, and Newfoundland are considerably higher compared to the remaining provinces because, due to the unavailability of natural gas, the ICE based cogeneration system was fuelled by propane, the most expensive of the fuels used in this study. In Quebec, while the price of propane is comparable to the price of heating oil, the fuel prices are relatively high and the electricity prices are the lowest in the country with a flat rate price of 5.22 ¢/kWh. This combination of higher fuel prices and lower electricity prices leads to a higher fuel cost for the ICE based cogeneration system compared to the base case. Prince Edward Island performed the best in terms of fuel costs compared to the remaining provinces in Eastern Canada. This is a result of subsidized propane prices, however, compared to Western Canada, the cost of fuel is still high.

As illustrated in Fig. 10, the increase in fuel cost compared to the base case is less in provinces where the difference between the

electricity and fuel price is higher. The results for Ontario illustrate another important point. Test case houses 13 and 15 (both in Ontario) have relatively low space heating demands (<60 GJ/yr) thus, while the pricing structure in Ontario is such that the increase in fuel costs compared to the base case should be low, this is not the case in these two test case houses. Since the thermal demand of these two houses is not high enough to utilize the heat generated by the cogeneration system, the increase in fuel cost compared to the base case is high. Test case house 14 has a higher space heating demand (~80 GJ) and the pricing structure in Ontario is favorable (i.e. electricity price higher than fuel price when compared in ¢/MJ), thus the total increase in fuel costs compared to the base case is lower compared to test case houses 13 and 14. Therefore, to be able to estimate the fuel cost increase expected using ICE based cogeneration, both the local electricity and fuel prices must be known, as well as the house specific energy demands.

Since the ICE based cogeneration system displaces grid-imported electricity in place of increased fuel consumption, the total fuel cost (including both natural gas/propane and electricity) is more dependent on the local fuel price than on the local electricity price. Fig. 11 shows the relationship between fuel price (natural gas or propane) and the total increase in fuel cost compared to the base case.

As illustrated in Fig. 11, the increase in total fuel cost increases as the fuel price increases. While the amount of thermal energy

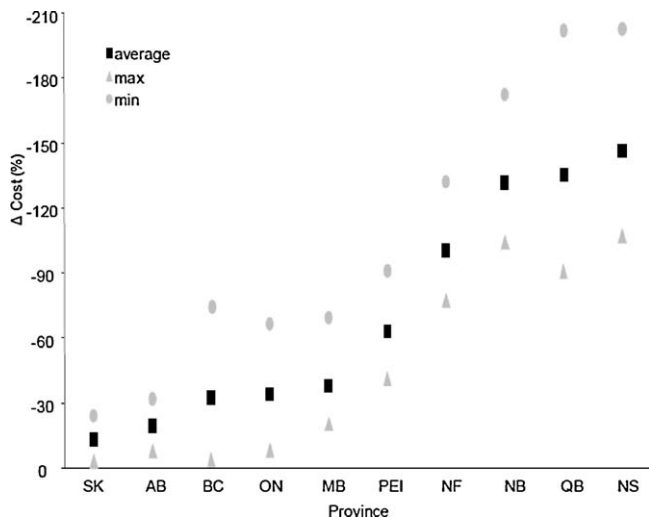


Fig. 9. ICE based cogeneration case-comparative fuel costs.

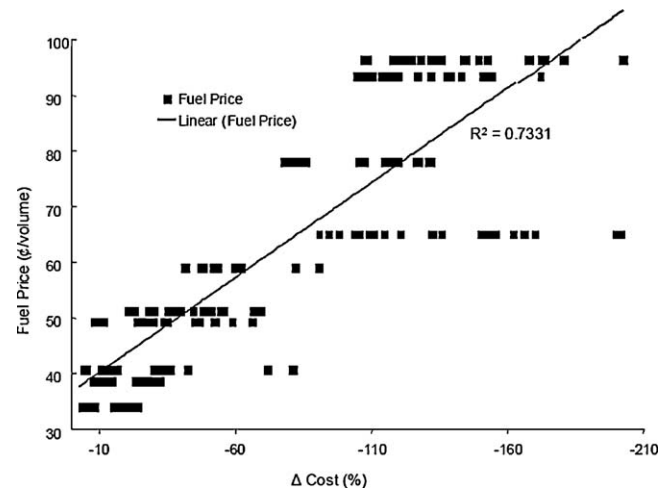


Fig. 11. Total fuel increase vs. fuel price.

generated by the cogeneration system in the non-space heating months may be comparable in different test case houses, the cost to the consumer depends on the local fuel cost. The cost of this wasted energy is a major contributing factor as to why the total fuel costs increase in all cases.

Maintenance and capital costs were not considered in this analysis, but have been estimated to be between 0.005–0.032 \$/kWh and 800–1300 \$/kW, respectively [2]. While the capital cost of ICE based cogeneration systems are the lowest compared to micro-turbine, fuel cell, and Stirling engine based cogeneration systems, the maintenance costs are the highest compared to these other prime movers. For a comprehensive review of the capital and maintenance costs of various residential cogeneration systems, refer to Onovwiona and Ugursal [2]. In addition, the value of distributed generation was not considered in the analysis. It can be argued that using ICE based cogeneration can provide savings by reducing investment in electricity generation capacity, reducing investment in electricity transmission, and distribution infrastructure and avoiding transmission losses.

5.3. GHG emissions

To calculate the GHG emissions for the base and ICE based cogeneration cases, electricity and fuel emissions factors had to be determined. Electricity generation in Canada is primarily from three sources, namely fossil fuels, hydro and nuclear. In general, nuclear plants and some hydro plants are operated at constant load; while fluctuations in electricity demand are met primarily by fossil fuel fired power plants and in some cases, load following hydro plants. Thus, it can be argued that the GHG emissions reduction calculated using the average electricity emissions factor result in a conservative estimate since it is assumed that the reduction in electricity consumption due to using ICE based cogeneration is uniformly distributed among all types of power plants and it does not take into account transmission and distribution losses. While a more accurate method to determine GHG emissions would be to use hourly GHG emissions factors, due to the unavailability of this data, a second set of emissions factors were determined to estimate the upper limit of GHG emissions reductions by assuming that all of the savings in electricity consumption comes from fossil fuel fired power plants including average transmission and distribution losses by province. The electricity generation and GHG emissions data for each province are presented in Ref. [13], while the estimates for transmission and distribution losses were taken from Guler [28]. Table 7 presents the high intensity electricity emissions factors as well as the transmission and distribution losses by province.

The potential reductions in GHG emissions using the ICE based cogeneration system compared to the base case are dependent on the local electricity emissions factor. The total GHG emissions (from electricity and fuel) compared to the base case are calculated

Table 7

High intensity electricity emissions factors by province and transmission and distribution losses.

Province	EF _{el,avg} (gCO _{2eq} /kWh)	Transmission and distribution losses (%)
British Columbia	24	8.0
Alberta	861	8.0
Saskatchewan	840	10.0
Manitoba	31	8.0
Ontario	222	8.0
Quebec	8	8.0
New Brunswick	433	7.3
Nova Scotia	759	8.3
Prince Edward Island	1120	7.3
Newfoundland	21	8.7

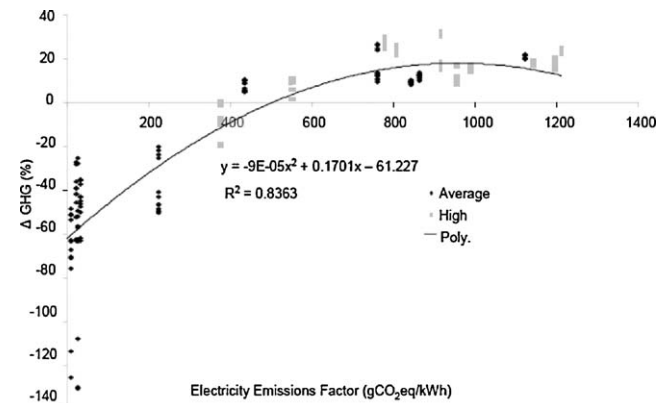


Fig. 12. Electricity emissions factor vs. comparative GHG emissions—1.0 kW ICE system.

according to a similar procedure used for electricity cost where a positive value indicates a reduction in GHG emissions. Fig. 12 presents the difference in total GHG emissions using the 1.0 kW ICE based cogeneration system compared to the base case as a function of electricity emissions factor.

As can be seen in Fig. 12, using the 1.0 kW ICE based cogeneration system results in a net reduction of GHG when the provincial electricity emissions factor is greater than, approximately 400 gCO_{2eq}/kWh. Test case houses simulated in Alberta, Saskatchewan, New Brunswick, Nova Scotia and Prince Edward Island, when evaluated using the average electricity emissions factor realized a net GHG reduction using ICE based cogeneration. Using the high intensity electricity emissions factor, all test case houses except for those in British Columbia, realized a net GHG reduction. Fig. 13 presents the difference in total GHG emissions using the 2.0 kW ICE based cogeneration system compared to the base case as a function of electricity emissions factor.

As can be seen in Fig. 13, using the 2.0 kW ICE based cogeneration system results in a net reduction of GHG when the provincial electricity emissions factor is greater than, approximately 750 gCO_{2eq}/kWh. Test case houses simulated in Alberta, Saskatchewan, Nova Scotia and Prince Edward Island, when evaluated using the average electricity emissions factor realized a net GHG reduction using ICE based cogeneration. Using the high intensity electricity emissions factor, all test case houses except for those in British Columbia and Quebec, realized a net GHG reduction.

According to the polynomial trend line used in both Figs. 12 and 13, the GHG reductions decrease when the electricity emissions factor is approximately 1200 gCO_{2eq}/kWh. This is a result of the

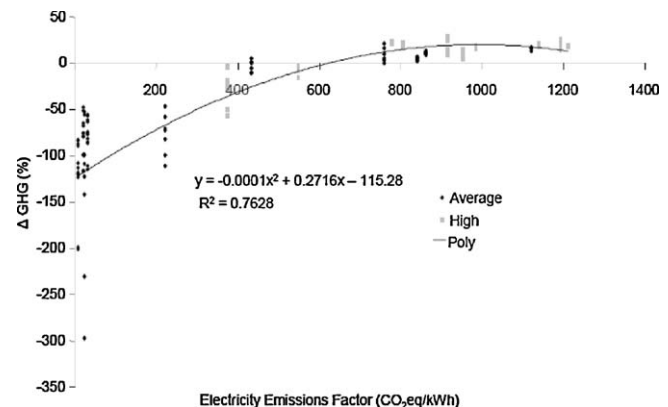


Fig. 13. Electricity emissions factor vs. comparative GHG emissions—2.0 kW ICE system.

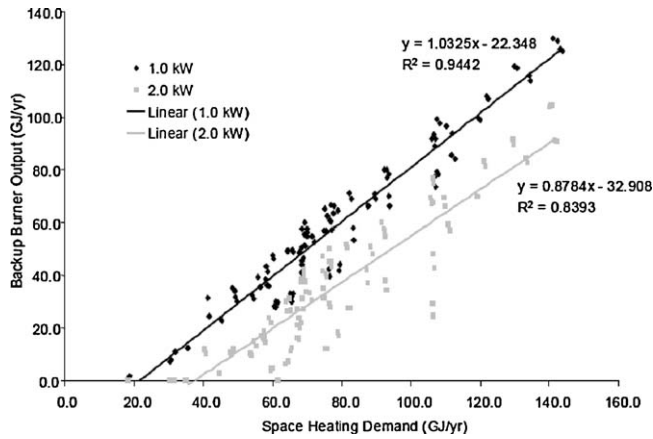


Fig. 14. Space heating demand vs. backup burner output.

test case house specific electricity demands being lower in PEI compared to the test case houses in provinces with electricity emissions factors around 800–900 gCO_{2eq}/kWh (i.e. Saskatchewan and Alberta). GHG reductions depend on both electricity demand and electricity emissions factor, thus because there is less electrical demand, there is a smaller GHG reduction, even though the electricity emissions factor is higher.

5.4. Backup burner

The amount of thermal energy required from the backup burner and the amount of heat dumped are important parameters when understanding how the overall cogeneration system operates, how much additional thermal energy is required and how much surplus thermal energy is not utilized. Fig. 14 presents the annual backup burner output as a function of annual space heating demand.

The cogeneration system operated in electricity priority control mode, thus the amount of thermal energy generated by the cogeneration system is dependent on the electricity demand of the house. Using the 1.0 kW system, the annual thermal output from the ICE based cogeneration system is between 70 and 80 GJ/yr. As illustrated in Fig. 14, the backup burner output, in the 1.0 kW case, is dependent on the space heating demand with a high prediction performance of $R^2 = 0.9442$. The prediction performance in the 2.0 kW case is lower, $R^2 = 0.8393$, because the range of thermal output from the ICE based cogeneration system is larger, 115–140 GJ depending on the electricity demand of the test case house. In the cases of low space heating demand (<30 GJ/yr), the 2.0 kW system was able to satisfy the thermal demand of the house without any contribution from the backup burner.

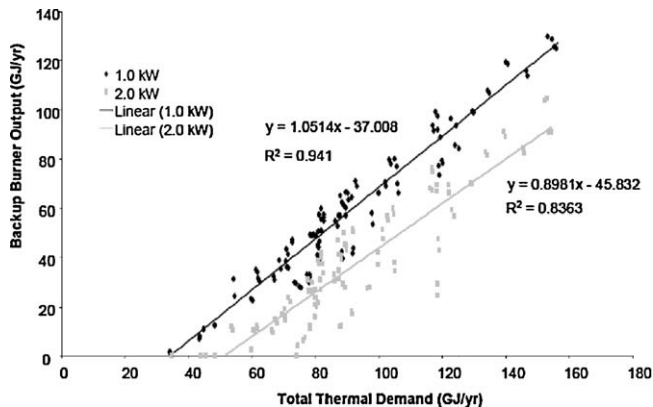


Fig. 15. Total thermal demand vs. backup burner output.

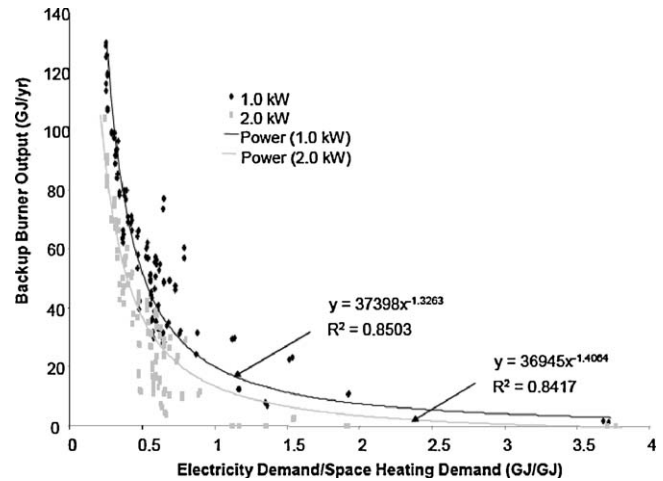


Fig. 16. Demand_{el}/Demand_{SH} vs. backup burner output.

Fig. 15 presents the annual backup burner output as a function of total annual thermal demand (sum of space and DHW demand).

As illustrated in Fig. 15, the backup burner output, in the 1.0 kW case, is dependent on the space heating demand with a high prediction performance of $R^2 = 0.941$. The prediction performance in the 2.0 kW case is lower, $R^2 = 0.8363$. Including the DHW demand to determine the required backup burner output only slightly reduces the prediction performance (<0.5%).

To account for the test case house specific electrical demand and the associated effect on backup burner output, the backup burner output is plotted as a function of electricity demand divided by space heating demand in Fig. 16. It can be seen that as the electricity demand and heating demand reach an even point, the backup burner output drops sharply, indicating of a turning point in the graph.

The amount of heat dumped is another important factor in this feasibility study and is a function of:

- Length of heating season
- Thermal output from the ICE based cogeneration system
- DHW demand
- Electricity demand
- Insulation level of test case house.

Figs. 17–19 present the annual space heating demand, annual DHW demand, total annual thermal demand, and ratio of annual electrical demand to annual space heating demand vs. the annual heat dump.

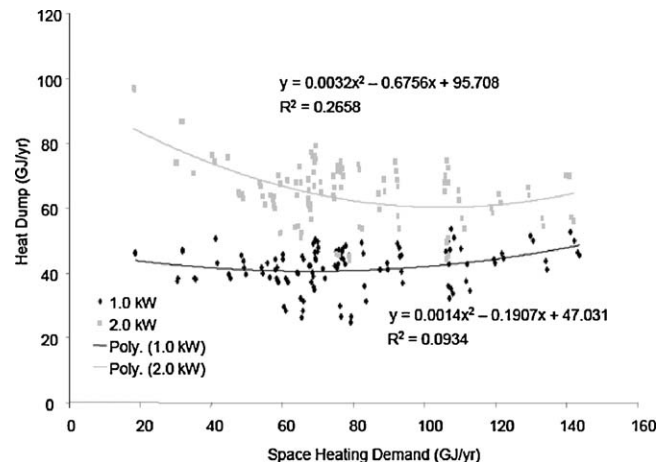


Fig. 17. Space heating demand vs. heat dump.

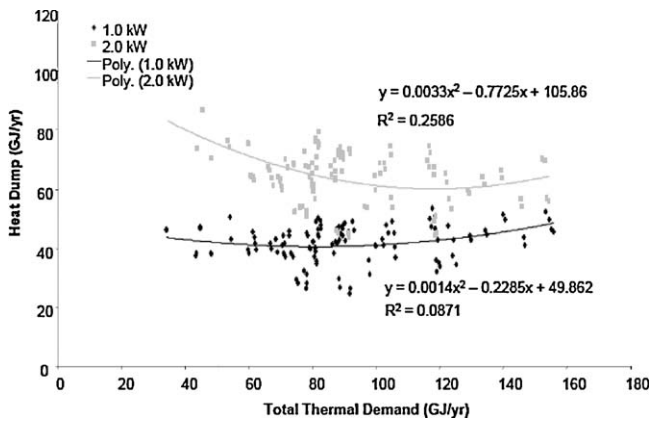


Fig. 18. Total thermal demand vs. heat dump.

Due to the number of variables involved in determining the annual heat dump, Figs. 17–19 show that there is not a direct correlation between annual space heating demand, annual DHW demand, total annual thermal demand, electricity demand divided by space heating demand and annual heat dump. Figs. 17–19 show the range of heat dump using the 1.0 kW and 2.0 kW systems. Using the 1.0 kW system, the heat dump is between 25 and 50 GJ/yr and using the 2.0 kW system, the annual heat dump is between 45 and 100 GJ/yr.

As mentioned before, since the cogeneration system used in this study followed the electricity demand of the house, heat was generated all year, which could not be fully utilized during the non-space heating months. The inability to fully utilize all of the generated energy leads to a fuel cost increase in all cases.

The ICE based cogeneration model used in this work is able to follow the electricity demand precisely. In reality however, an actual system would not be able to exactly follow the electrical demand of the house. Thus, either battery storage, or the ability to export to the grid would likely be required. Also, the ICE based cogeneration system did not modulate its output between time steps, rather instantaneously adjusted its output to match the demand at the given time step. It is recognized that this is not realistic behaviour, and that an actual system would continuously adjust its power output. In addition, the ICE based cogeneration model used in this study has a maximum electrical efficiency of 22.48%. It is recognized that there are commercially available system with electrical efficiencies as high as 30% [29] and using these systems would likely provide a further reduction in fuel costs compared to the figures determined in this work.

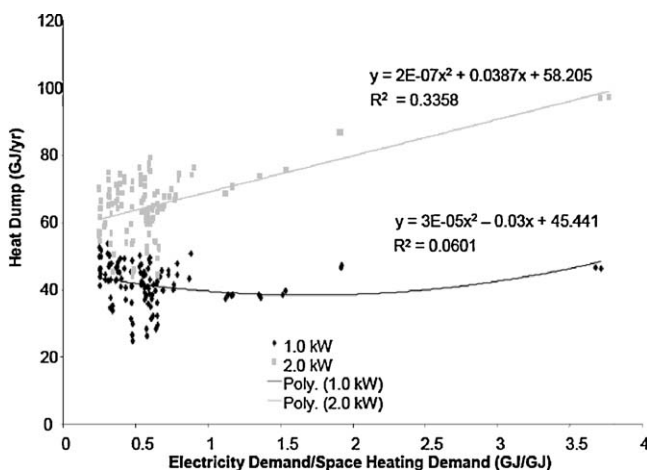


Fig. 19. Demand_{el}/Demand_{SH} vs. heat dump.

In general, operating residential CHP systems to follow electric load is not the best way to utilize the energy generated. Especially in residential applications, electrical loads fluctuate dramatically depending on the time of day, and to a lesser extent, on the time of year. In most residential applications, there is not a large enough year round constant thermal demand to utilize all of the thermal energy generated. Unless the thermal energy can be used during the non-space heating months by a heat-driven cooling system, the annual CHP efficiency is reduced thereby reducing the potential fuel cost savings and GHG reductions potential. While electricity priority controlled residential cogeneration has its drawbacks, thermal priority controlled residential cogeneration does as well. In the case of thermal priority controlled residential cogeneration, the system is idle likely during much of the non-space heating season which leads to an increase in payback time.

Generally speaking, implementing, sizing and controlling residential cogeneration systems continues to be a challenge and is dependent on many factors including:

- House specific thermal demands
- House specific electrical demands
- Local fuel prices and availability
- Local electricity prices
- Electricity emissions factors
- Local regulations on connecting distributed generation devices to central electricity grid
- High capital costs compared to conventional systems
- Lack of knowledge and understanding regarding cogeneration among home owners.

6. Conclusions

Feasibility of residential application of ICE based cogeneration systems in cold climate was studied using ESP-r building simulation software. Canadian residential databases were used for simulation. Through comparison between base case (conventional) energy system and the ICE based cogeneration system, it was found that, the economic viability, in terms of fuel costs, of the ICE based residential cogeneration controlled using electricity priority control is dependent on the provincial fuel and electricity prices. The CHP efficiency of the 1.0 kW system was found to be higher than the 2.0 kW system. There is a possibility that all the heat produced by the system cannot be utilized in non-space-heating months contributing to higher fuel cost. However, the ICE based system can provide savings by reducing investment in electricity generation capacity, reducing investment in electricity transmission, and distribution infrastructure and avoiding transmission losses. It was shown that using the 1.0 kW ICE based cogeneration system results in a net reduction of GHG when the provincial electricity emissions factor is greater than, approximately 400 gCO_{2eq}/kWh. The focus of further publications is the detailed provincial behavior of the system.

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